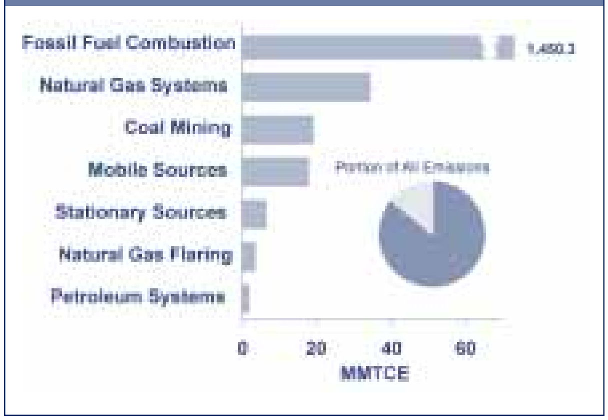
2. Energy

Energy-related activities were the primary source of anthropogenic greenhouse gas emissions, accounting for 86 percent of total U.S. emissions annually on a carbon equivalent basis in 1996. This included 99, 33, and 20 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a carbon equivalent basis (see Figure 2-1), while the non-CO_2 emissions from energy represented a much smaller portion of total national emissions (4 percent collectively).

Figure 2-1

1996 Energy Sector GHG Sources



Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted. Due to the relative importance of fossil fuel combustion related CO_2 emissions, they are considered separately from other emissions. Fossil fuel combustion also emits CH_4 and N_2O, as well as criteria pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Fossil fuel combustion—from stationary and mobile sources—was the second largest source N_2O emissions in the United States, and overall energy related activities are the largest sources of criteria pollutant emissions.

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. Carbon dioxide emissions from these activities, however, are not included in national emissions totals under the Energy sector because biomass fuels are of biogenic origin. It is assumed that the carbon released when biomass is consumed is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to be added to the atmosphere. The net impacts of land-use and forestry activities on the carbon cycle are accounted for under the Land-use change and Forestry sector.

Overall, emissions from the Energy sector have increased from 1990 to 1996 due, in part, to the strong performance of the U.S. economy. Over this period, the U.S. Gross Domestic Product (GDP) grew approximately 13 percent, or at an annualized rate of about 2 percent. This robust economic activity increased the demand for fossil fuels, with an associated increase in greenhouse gas emissions. Table 2-1 summarizes emissions from the Energy sector in units of million metric tons of carbon equivalents (MMTCE), while unweighted gas emissions in teragrams

Table 2-1: Emissions from the Energy Sector (MMTCE)

Gas/Source	1990	1991	1992	1993	1994	1995	1996
CO_2	**1,333.4**	**1,318.7**	**1,338.8**	**1,370.5**	**1,392.6**	**1,402.4**	**1,453.8**
Fossil Fuel Combustion	1,331.4	1,316.4	1,336.6	1,367.5	1,389.6	1,398.7	1,450.3
Natural Gas Flaring	2.0	2.2	2.2	3.0	3.0	3.7	3.5
Biomass-Ethanol*	1.6	1.2	1.5	1.7	1.8	2.0	1.4
Biomass-Wood*	47.0	46.9	49.0	47.6	48.4	50.2	53.2
International Bunker Fuels*	22.7	24.0	24.9	22.9	22.3	23.6	22.5
Non-fuel Use Carbon Stored*	(69.2)	(68.8)	(70.6)	(73.1)	(78.2)	(78.8)	(81.7)
CH_4	**62.2**	**61.4**	**61.3**	**58.5**	**58.6**	**59.5**	**58.4**
Stationary Sources	2.3	2.3	2.4	2.3	2.3	2.4	2.5
Mobile Sources	1.5	1.4	1.4	1.4	1.4	1.4	1.4
Coal Mining	24.0	22.8	22.0	19.2	19.4	20.3	18.9
Natural Gas Systems	32.9	33.3	33.9	34.1	33.9	33.8	34.1
Petroleum Systems	1.6	1.6	1.6	1.6	1.6	1.6	1.5
N_2O	**16.9**	**17.6**	**18.5**	**19.3**	**20.1**	**20.4**	**20.5**
Stationary Sources	3.7	3.7	3.7	3.8	3.8	3.8	4.0
Mobile Sources	13.2	13.9	14.8	15.6	16.3	16.6	16.5
Total	**1,412.5**	**1,397.6**	**1,418.6**	**1,448.4**	**1,471.3**	**1,482.3**	**1,532.7**

+ Does not exceed 0.05 MMTCE
* These figures are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 2-2: Emissions from the Energy Sector (Tg)

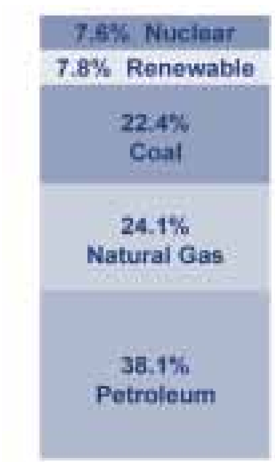
Gas/Source	1990	1991	1992	1993	1994	1995	1996
CO_2	**4,889.2**	**4,835.2**	**4,908.8**	**5,025.1**	**5,106.3**	**5,142.2**	**5,330.6**
Fossil Fuel Combustion	4,881.9	4,826.9	4,900.7	5,014.1	5,095.2	5,128.5	5,317.8
Natural Gas Flaring	7.3	8.2	8.1	11.0	11.1	13.7	12.7
Biomass-Ethanol*	5.7	4.5	5.5	6.1	6.7	7.2	5.1
Biomass-Wood*	172.2	171.9	179.7	174.5	177.5	184.2	195.0
International Bunker Fuels*	83.4	87.8	91.3	83.8	81.7	86.7	82.4
Non-fuel Use Carbon Stored*	(253.8)	(252.3)	(258.8)	(268.2)	(286.6)	(289.1)	(299.7)
CH_4	**10.9**	**10.7**	**10.7**	**10.2**	**10.2**	**10.4**	**10.2**
Stationary Sources	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Mobile Sources	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Coal Mining	4.2	4.0	3.8	3.4	3.4	3.6	3.3
Natural Gas Systems	5.7	5.8	5.9	5.9	5.9	5.9	5.9
Petroleum Systems	0.3	0.3	0.3	0.3	0.3	0.3	0.3
N_2O	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Stationary Sources	+	+	+	+	+	+	+
Mobile Sources	0.2	0.2	0.2	0.2	0.2	0.2	0.2

+ Does not exceed 0.05 Tg
* These figures are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

(Tg) are provided in Table 2-2. Overall, emissions due to energy-related activities increased by more than 9 percent from 1990 to 1996, rising from 1,412.5 MMTCE in 1990 to 1,532.7 MMTCE in 1996. The growth in emissions from 1995 to 1996 (3.4 percent) was the largest percent increase over the seven year period. This growth rate in emissions actually exceeded the overall growth rate in the economy. Discussion of specific Energy sector trends is presented below.

Figure 2-2

1996 U.S. Energy Consumption



Source: DOE/EIA-0384(96), Annual Energy Review 1996, Table 1.3, July 1997

Carbon Dioxide Emissions from Fossil Fuel Combustion

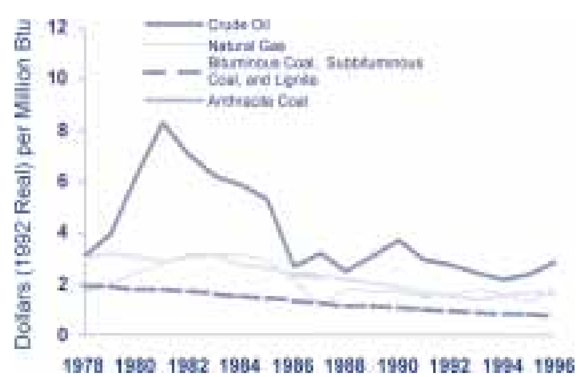
The majority of energy consumed in the United States, approximately 84.5 percent, was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum in 1996 (see Figure 2-2). Of the remaining, 7.6 percent was supplied by nuclear electric power and 7.8 percent from renewable sources (EIA 1997a).

As fossil fuels are combusted, the carbon stored in the fuels is emitted as CO_2 and smaller amounts of other gases, including methane (CH_4), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). These other gases are emitted as a by-product of incomplete fuel combustion. The amount of carbon in the fuel varies significantly by fuel type. For example, coal contains the highest amount of carbon per unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about 55 percent.[1] Petroleum supplied the largest share of U.S. energy demands, accounting for an average of 39 percent of total energy consumption over the period of 1990 through 1996 (see Figure 2-2). Natural gas and coal followed in order of importance, accounting for an average of 24 and 22 percent of total consumption, respectively. Most petroleum was consumed in the transportation end-use sector, while the vast majority of coal was used by electric utilities, with natural gas consumed largely in the industrial and residential end-use sectors.

Emissions of CO_2 from fossil fuel combustion increased at an annualized rate of 1.4 percent from 1990 to 1996. The major factor behind this trend was a robust domestic economy, combined with relatively low energy prices. For example, petroleum prices had changed little in real terms since the 1970s, with coal prices actually declining in real terms compared to prices in the 1970s (EIA 1997a) (see Figure 2-3). After 1990, when carbon dioxide emissions from fossil fuel combustion were 1,331.4 MMTCE (4,881.9 Tg), there was a slight decline

Figure 2-3

Fossil Fuel Production Prices



Source: DOE/EIA-0384(96), Annual Energy Review 1996, July, 1997, Table 3.1

[1] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Table 2-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and End-Use Sector (MMTCE)

Fuel/End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Coal	**481.6**	**475.8**	**478.3**	**494.7**	**496.7**	**498.5**	**524.0**
Residential	1.6	1.4	1.5	1.5	1.4	1.4	1.4
Commercial	2.4	2.2	2.2	2.2	2.1	2.1	2.1
Industrial	68.5	64.8	62.6	62.2	62.7	62.1	59.4
Transportation	-	-	-	-	-	-	-
Utilities	409.0	407.2	411.8	428.7	430.2	432.7	460.9
U.S. Territories	0.1	0.2	0.2	0.2	0.3	0.3	0.3
Natural Gas	**273.1**	**277.9**	**286.2**	**296.3**	**302.1**	**314.8**	**318.6**
Residential	65.1	67.5	69.4	73.4	71.8	71.7	77.4
Commercial	38.8	40.4	41.5	43.1	42.9	45.9	47.4
Industrial	118.2	120.0	125.8	131.0	133.3	139.7	143.0
Transportation	9.8	8.9	8.8	9.3	10.2	10.4	10.5
Utilities	41.2	41.1	40.7	39.5	44.0	47.2	40.3
U.S. Territories	-	-	-	-	-	-	-
Petroleum	**576.7**	**562.6**	**572.0**	**576.4**	**593.5**	**587.7**	**609.0**
Residential	23.9	24.4	24.8	26.2	25.3	25.7	27.2
Commercial	18.0	17.1	16.1	14.9	14.9	15.0	15.3
Industrial	100.2	94.5	104.3	98.3	102.2	97.9	104.6
Transportation	399.0	391.1	397.3	404.1	416.6	421.7	434.3
Utilities	26.6	25.1	19.9	22.5	20.6	14.0	15.6
U.S. Territories	9.0	10.5	9.6	10.4	11.2	10.9	10.6
Geothermal*	**0.1**	**0.1**	**0.1**	**0.1**	**+**	**+**	**+**
Total	**1,331.4**	**1,316.4**	**1,336.6**	**1,367.5**	**1,389.6**	**1,398.7**	**1,450.3**

- Not applicable
+ Does not exceed 0.05 MMTCE
* Although not technically a fossil fuel, geothermal energy related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

of emissions in 1991, followed by an increase to 1,450.3 MMTCE (5,317.8 Tg) in 1996 (see Table 2-3 and Table 2-4). Overall, CO_2 emissions from fossil fuel combustion increased by 9 percent over the seven year period and rose by a dramatic 3.7 percent in the final year alone.

Consumption of all fossil fuels increased, with about 38 percent of the increase in CO_2 emissions from fossil fuel combustion since 1990 coming from natural gas consumption, 36 percent from coal, and 26 percent from petroleum. From 1995 to 1996, absolute emissions from coal grew the most (an increase of 25.5 MMTCE or 5 percent), while emissions from natural gas changed the least (an increase of 3.8 MMTCE or 1 percent) as electric utilities increased their consumption of coal while shifting away from natural gas because of higher gas prices. Alone, emissions from electric utility coal combustion increased by 6.5 percent from 1995 to 1996.

In 1996, the U.S. coal industry produced the largest amount of coal ever. Preliminary data (EIA 1997b) show that annual U.S. coal consumption totaled 892 teragrams (Tg) in 1996, a 4.5 percent increase from 1995, the combustion of which accounted for roughly half of the total increase in emissions during the same period.

Despite slightly higher prices, the consumption of petroleum products in 1996 increased 3.5 percent from the previous year, accounting for about 43 percent of the increase in CO_2 emissions from fossil fuel combustion. More than half of the increase in emissions from petroleum was due to higher fuel consumption for transportation activities.

Table 2-4: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and End-Use Sector (Tg)

Fuel/End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Coal	**1,765.7**	**1,744.7**	**1,753.8**	**1,813.9**	**1,821.3**	**1,827.8**	**1,921.4**
Residential	5.8	5.3	5.4	5.3	5.2	5.1	5.1
Commercial	8.7	8.0	8.1	8.1	7.9	7.6	7.6
Industrial	251.0	237.6	229.5	228.0	229.9	227.7	217.8
Transportation	-	-	-	-	-	-	-
Utilities	1,499.7	1,493.2	1,510.0	1,571.7	1,577.4	1,586.4	1,689.9
U.S. Territories	0.4	0.6	0.8	0.7	0.9	0.9	0.9
Natural Gas	**1,001.3**	**1,019.1**	**1,049.5**	**1,086.5**	**1,107.7**	**1,154.3**	**1,168.1**
Residential	238.5	247.3	254.5	269.1	263.3	263.0	283.8
Commercial	142.4	148.2	152.3	158.2	157.4	168.2	173.7
Industrial	433.2	440.1	461.2	480.4	488.6	512.1	524.2
Transportation	36.0	32.8	32.1	33.9	37.2	38.1	38.6
Utilities	151.1	150.6	149.3	144.9	161.2	173.0	147.9
U.S. Territories	-	-	-	-	-	-	-
Petroleum	**2,114.6**	**2,062.9**	**2,097.3**	**2,113.6**	**2,166.0**	**2,146.2**	**2,228.2**
Residential	87.7	89.4	90.9	96.1	92.8	94.4	99.8
Commercial	66.1	62.6	59.1	54.7	54.7	54.9	56.2
Industrial	367.2	346.3	382.3	360.5	374.6	359.1	383.7
Transportation	1,463.1	1,434.1	1,456.8	1,481.8	1,527.4	1,546.3	1,592.5
Utilities	97.6	91.9	73.1	82.5	75.6	51.3	57.2
U.S. Territories	32.8	38.5	35.1	38.0	40.9	40.1	38.8
Geothermal*	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**
Total	**4,881.9**	**4,826.9**	**4,900.7**	**5,014.1**	**5,095.2**	**5,128.5**	**5,317.8**

- Not applicable

+ Does not exceed 0.05 Tg

* Although not technically a fossil fuel, geothermal energy related CO_2 emissions are included for reporting purposes.

Note: Totals may not sum due to independent rounding.

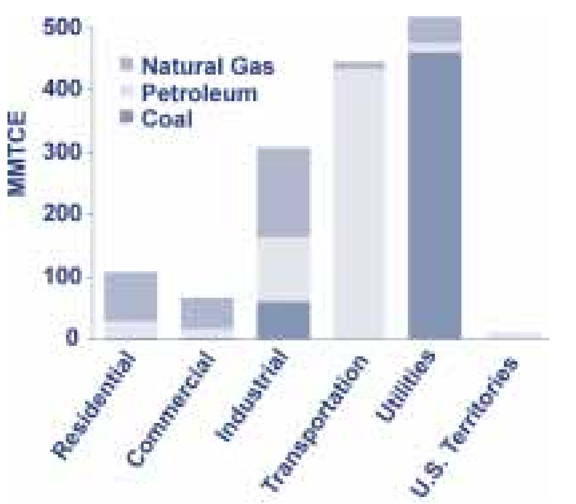
From 1995 to 1996, emissions from natural gas rose only 1.2 percent, largely due to higher natural gas prices in 1996 that reversed a 10 year long trend of declining prices. The U.S. Department of Energy's Energy Information Administration cited low levels of storage and unusually cold weather as the two main reasons for this price increase (EIA 1997e). Natural gas related emissions from the residential sector rose by 7.9 percent while the utility sector experienced a dramatic 14.6 percent decrease. This sharp reduction can be explained by a 33 percent increase in the price of natural gas for utilities (EIA 1997e). Increased consumption of natural gas accounted for only 7.5 percent of the increase in fossil fuel CO_2 emissions from 1995 to 1996.

End-Use Sector Contributions

The four end-use sectors contributing to CO_2 emissions from fossil fuel combustion include: industrial, transportation, residential, and commercial. Electric utilities also emit CO_2, although these emissions are produced as they consume fossil fuel to provide electricity to one of the four end-use sectors. For the discussion below, utility emissions have been distributed to each end-use sector based upon their aggregate electricity consumption. Emissions from utilities are addressed separately after the end-use sectors have been discussed. Emissions from U.S. territories are also calculated separately due to a lack of end-use specific consumption data. Table 2-5 and Figure 2-4 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Figure 2-4

1996 CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector and Fuel Type



* Utilities also includes emissions of 0.04 MMTCE from geothermal based electricity generation

Industrial End-Use Sector

The industrial end-use sector accounted for approximately one-third of CO_2 emissions from fossil fuel combustion. On average, nearly 64 percent of these emissions resulted from the direct consumption of fossil fuels in order to meet industrial demand for steam and process heat. The remaining 36 percent of industrial energy needs was met by electricity for uses such as motors, electric furnaces, ovens, and lighting.

Coal consumption by industry declined in 1996 from the previous year's levels. At coke plants, consumption dropped by 3.9 percent. Consumption by other industries declined by 2.9 percent (EIA 1997b). Industrial use of natural gas and petroleum were up in 1996 by 2.4 percent and 5.0 percent, respectively, from 1995 levels.

The industrial end-use sector was also the largest user of fossil fuels for non-energy applications. Fossil fuels used for producing fertilizers, plastics, asphalt, or lubricants can sequester or store carbon in products for long periods of time. Asphalt used in road construction, for example, stores carbon essentially indefinitely. Similarly, fossil fuels used in the manufacture of materials like plastics also store carbon, releasing it if the material is burned. Carbon stored by industrial or transportation non-fuel uses of fossil fuels rose 18 percent between 1990 and 1996 (69.2 MMTCE and 81.7 MMTCE, respectively).

Transportation End-Use Sector

The transportation sector accounted for slightly over 30 percent of U.S. CO_2 emissions from fossil fuel combustion. Virtually all of the energy consumed in this sector came from petroleum-based products, with nearly two-thirds resulting from gasoline consumption in automobiles and other on-road vehicles. Other uses, including diesel fuel for the trucking industry and jet fuel for aircraft, accounted for the remainder.

Following the overall trend in U.S. energy consumption, fossil fuel combustion for transportation grew steadily after declining in 1991, resulting in an increase in CO_2 emissions from 409.6 MMTCE (1,501.7 Tg) in 1990 to 445.5 MMTCE (1,633.5 Tg) in 1996. During this seven year period, petroleum consumption—mainly motor gasoline, distillate fuel oil (e.g., diesel), and jet fuel—in the transportation end-use sector increased 8.5 percent. This increase was slightly offset by decreases in the consumption of avia-

Table 2-5: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (MMTCE)*

End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Residential	253.0	257.0	255.7	271.6	268.6	269.7	286.7
Commercial	206.7	206.4	205.3	212.2	214.1	219.2	229.9
Industrial	453.1	441.6	459.0	459.0	468.1	465.7	477.5
Transportation	409.6	400.8	406.7	414.1	427.4	432.8	445.5
U.S. Territories	9.1	10.7	9.8	10.6	11.4	11.2	10.8
Total	**1331.4**	**1316.4**	**1336.6**	**1367.5**	**1389.6**	**1398.7**	**1450.3**

* Emissions from fossil fuel combustion by electric utilities are allocated based on electricity consumption by each end-use sector.
Note: Totals may not sum due to independent rounding.

Figure 2-5

Motor Vehicle Fuel Efficiency

Source: DOE/EIA-0384(96), Annual Energy Review 1996, July, 1997, Table 3.13

tion gasoline and residual fuel. Overall, motor vehicle fuel efficiency stabilized in the 1990s after increasing steadily since 1977 (EIA 1997a). This trend is due, in part, to new motor vehicle sales being increasingly dominated by less fuel-efficient light-duty trucks and sport-utility vehicles (see Figure 2-5). Moreover, declining petroleum prices during these years—with the exception of 1996, when the average price increased—combined with a stronger economy, were largely responsible for an overall increase in vehicle miles traveled by on-road vehicles (see Figure 2-6).

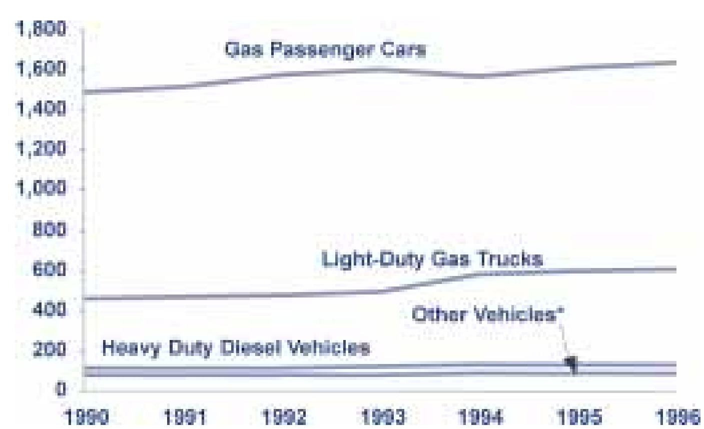
Table 2-6 provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. On average 60 percent of the emissions from this end-use sector were the result of the combustion of motor gasoline in passenger cars and light-duty trucks. Diesel highway vehicles and jet aircraft were also significant contributors, each accounting for, on average, 13 percent of CO_2 emissions from the transportation end-use sector. It should be noted that the U.S. Department of Transportation's Federal Highway Administration altered its definition of light-duty trucks in 1995 to include sport utility vehicles and minivans; previously these vehicles were included under the passenger cars category. As a consequence of this reclassification, a discontinuity exists in the time series in Table 2-6 for both passenger cars and light-duty trucks.

Residential and Commercial End-Use Sectors

From 1990 to 1996, the residential and commercial end-use sectors, on average, accounted for 19 and 16 percent, respectively, of CO_2 emissions from fossil fuel combustion. Unlike in other major end-use sectors, emissions from the residential end-use sector did not decline in 1991, but they did decrease in 1992 and 1994, then grew steadily through 1996. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with about two-thirds of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs.

Figure 2-6

U.S. Vehicle Miles Traveled



* "Other Vehicles" includes heavy duty gas vehicles, diesel passenger cars, light duty diesel trucks, and motorcycles
Source: EPA/OAQPS

Important Note: There is a discontinuity in the VMT data starting in 1994. Before 1994, vans, minivans, and sport utility vehicles were included in the passenger car category. Beginning in 1994, all three vehicle types (passenger or cargo) were included in the light duty truck category.

Natural gas consumption in the residential and commercial end-use sectors increased in 1996 by 7.6 and 3.3 percent, respectively. This increase is attributed to record low temperatures at the start of 1996 and new consumers in the natural gas market (EIA 1997e). Petroleum consumption increased about 6 and 2 percent from 1995

Table 2-6: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMTCE)

Fuel/Vehicle Type	1990	1991	1992	1993	1994	1995	1996
Motor Gasoline	**260.9**	**259.5**	**263.4**	**269.3**	**273.7**	**279.9**	**285.5**
Passenger Cars*	167.3	165.9	170.0	171.5	170.5	158.1	161.3
Light-Duty Trucks*	74.9	74.7	74.6	77.8	84.2	101.3	103.4
Other Trucks	11.3	11.2	11.2	11.7	10.4	10.9	11.2
Motorcycles	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Buses	0.6	0.6	0.6	0.7	0.9	0.8	0.8
Construction Equipment	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Agricultural Machinery	1.2	1.2	1.2	2.0	2.1	2.2	2.2
Boats (Recreational)	4.6	4.8	4.7	4.6	4.5	5.3	5.4
Distillate Fuel Oil (Diesel)	**73.4**	**70.5**	**73.4**	**75.2**	**80.4**	**81.8**	**86.1**
Passenger Cars*	2.0	1.9	2.0	2.0	2.0	1.8	1.9
Light-Duty Trucks*	2.5	2.4	2.5	2.6	2.8	3.3	3.4
Other Trucks	45.3	43.3	45.1	47.7	51.7	52.7	55.5
Buses	2.2	2.2	2.3	2.3	2.3	2.7	2.8
Construction Equipment	2.9	2.9	2.9	2.9	2.9	2.8	3.0
Agricultural Machinery	6.4	6.3	6.4	6.4	6.3	6.2	6.5
Boats (Freight)	5.0	4.8	5.1	4.6	4.6	4.3	4.6
Locomotives	7.3	6.7	7.3	6.6	7.8	8.0	8.4
Jet Fuel	**55.0**	**53.0**	**52.3**	**52.7**	**54.9**	**54.2**	**56.7**
General Aviation	1.7	1.5	1.3	1.3	1.2	1.4	1.5
Domestic Carriers	32.0	29.6	30.5	30.9	32.0	32.8	34.2
International Carriers	5.1	5.1	5.3	5.3	5.5	5.7	6.0
Military Aircraft	16.3	16.9	15.2	15.2	16.1	14.3	15.0
Aviation Gasoline	**0.8**	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**
General Aviation	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Residual Fuel Oil	**6.7**	**5.5**	**5.5**	**4.2**	**4.6**	**2.9**	**3.1**
Boats (Freight)	6.7	5.5	5.5	4.2	4.6	2.9	3.1
Natural Gas	**9.8**	**8.9**	**8.8**	**9.3**	**10.2**	**10.4**	**10.5**
Passenger Cars*	+	+	+	+	+	+	+
Light-Duty Trucks*	+	+	+	+	+	+	+
Buses	+	+	+	+	+	+	+
Pipeline	9.8	8.9	8.8	9.2	10.1	10.4	10.5
LPG	**0.4**	**0.3**	**0.3**	**0.3**	**0.5**	**0.5**	**0.6**
Light-Duty Trucks*	0.1	0.1	0.1	0.1	0.2	0.3	0.3
Other Trucks	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Buses	+	+	+	+	+	+	+
Electricity	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Buses	+	+	+	+	+	+	+
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pipeline	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Lubricants	**1.8**	**1.6**	**1.6**	**1.6**	**1.7**	**1.7**	**1.6**
Total	**409.6**	**400.8**	**406.7**	**414.1**	**427.4**	**432.8**	**445.5**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMTCE
*In 1995, the U.S. Federal Highway Administration modified the definition of light-duty trucks to include minivans and sport utility vehicles. Previously, these vehicles were included under the passenger cars category. Hence the sharp drop in emissions for passenger cars from 1994 to 1995 was observed. This gap, however, was offset by an equivalent rise in emissions from light-duty trucks.

to 1996 in the residential and commercial end-use sectors, respectively. Coal consumption was a small component of energy use in these end-use sectors.

Electric Utilities

As one of the largest consumers of fossil fuels in the United States (averaging 28 percent of national fossil fuel consumption and 88 percent of coal consumption on an energy content basis), electric utilities were collectively the largest producers of U.S. CO_2 emissions, accounting for 35 percent. The United States relies on electricity to meet a significant portion of its energy requirements for uses such as lighting, heating, electric motors, and air conditioning. Because electric utilities consume such a substantial portion of U.S. fossil fuels to generate this electricity, the type of fuel they use has a significant effect national CO_2 emissions. Some of this electricity was generated with the lowest CO_2 emitting energy technologies, particularly non-fossil options such as hydropower or nuclear energy; however, electric utilities still accounted for 88 percent of all coal consumed in the United States in 1996. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

The combustion of coal was used to generate 57 percent of the electricity consumed in the United States in 1996, up from 55 percent in 1995 (EIA 1997f). From 1990 to 1996, coal emissions from utilities increased 12.7 percent. This increase in coal-related emissions from utilities was alone responsible for 56 percent of the overall rise in CO_2 emissions from fossil fuel combustion.

Balancing the increased consumption of coal by utilities, their consumption of natural gas declined in 1996 due to rising gas prices relative to coal and petroleum (EIA 1997a). Utility natural gas use increased significantly in 1994 and 1995, as the natural gas industry stabilized following a series of cold winters and a period of industry restructuring. However, in 1996 utility gas prices increased by a dramatic 33 percent (EIA 1997a), making gas-based electricity generation less economical. Consequently, natural gas consumption by electric utilities declined by 15 percent in 1996. Utilities compensated primarily by burning more coal, emissions from which increased by 6.5 percent from 1995 to 1996. Petroleum constitutes only a small portion of utility fossil fuel consumption (3.4 percent in 1996**,** occurring mostly in the eastern United States).

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). A detailed description of the U.S. methodology is presented in Annex A, and is characterized by the following five steps:

1. *Determine fuel consumption by fuel type and end-use sector*. By aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, oil, gas), and secondary fuel category (e.g., gasoline, distillate fuel, etc.), estimates of total U.S. energy consumption for a particular year were made.[2]
2. *Determine the total carbon content of fuels consumed*. Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon were converted to CO_2. The carbon emission coefficients used by the United States are presented in Annex A.
3. *Subtract the amount of carbon stored in products.* Non-fuel uses of fossil fuels can result in storage of some or all of the carbon contained in the fuel for some period of time, depending on the end-use. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon for extended periods of time, while other products, such as lubricants or plastics, lose or emit some carbon when they are used and/or burned as waste. The amount of carbon sequestered or stored in non-energy uses of fossil fuels was based on the best available data on the end-uses and ultimate fate of the various energy products. These non-energy uses occurred in the industrial and transportation end-use sectors. Carbon sequestered by these uses was 69 MMTCE in 1990, rising to 82 MMTCE in 1996.
4. *Adjust for carbon that does not oxidize during combustion*. Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot or other by-products of inefficient combustion. The estimated amount of carbon not oxidized due to inefficiencies during the combustion process ranged from 1 percent for petroleum and coal to 0.5 percent for natural gas (see Annex A).

[2] Fuel consumption by U.S. territories (i.e. American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed about 11 MMTCE of emissions in 1995 and 1996.

5. *Subtract emissions from international bunker fuels.* According to the IPCC guidelines (IPCC/UNEP/OECD/IEA 1997) emissions from international transport activities, or bunker fuels, should not be included in national totals. Because U.S. energy consumption statistics include these bunker fuels—primarily residual oil—as part of consumption by the transportation end-use sector, emissions from this source were calculated separately and subtracted. The calculations for emissions from bunker fuels follows the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized). Carbon dioxide emissions from international bunkers were 22.7 MMTCE (83.4 Tg) in 1990, rising to 24.9 MMTCE (91.3 Tg) in 1992 and then declining to 22.5 MMTCE (82.4 Tg) in 1996.
6. *Allocate transportation emissions by vehicle type.* Because the transportation end-use sector was the largest direct consumer of fossil fuels in the United States, a more detailed accounting of carbon dioxide emissions is provided. Fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Specific data by vehicle type were not available for 1996; therefore, the 1995 percentage allocations were applied to 1996 fuel consumption data in order to estimate emissions in 1996. Military aircraft jet fuel consumption was assumed to account for the difference between total U.S. jet fuel consumption (as reported by DOE/EIA) and civilian airline consumption (as reported by DOT/BTS).

Data Sources

Fuel consumption, carbon content of fuels, and percent of carbon sequestered in non-fuel uses data were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). Fuel consumption data were obtained primarily from the *Monthly Energy Review* (EIA 1997d). IPCC (IPCC/UNEP/OECD/IEA 1997) provided combustion efficiency rates for petroleum and natural gas. Bechtel (1993) provided the combustion efficiency rates for coal. Vehicle type fuel consumption data was taken from the *Transportation Energy Databook* prepared by the Center for Transportation Analysis at Oak Ridge National Laboratory (DOE 1993, 1994, 1995, 1996, 1997).

For consistency of reporting, the IPCC has recommended that national inventories report energy data (and emissions from energy) using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted, in principle is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and consumption of products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

There are uncertainties, however, concerning the consumption data sources, carbon content of fuels and products, and combustion efficiencies. For example, given the same primary fuel type (e.g., coal), the amount of carbon contained in the fuel per unit of useful energy can vary. Non-energy uses of the fuel can also create situations where the carbon is not emitted to the atmosphere (e.g., plastics, asphalt, etc.) or is emitted at a much delayed rate. The proportions of fuels used in these non-fuel production processes that result in the sequestration of carbon have been assumed. Additionally, inefficiencies in the combustion process, which can result in ash or soot remaining unoxidized for long periods, were also assumed. These factors all contribute to the uncertainty in the CO_2 estimates. For the United States, however, these uncertainties are believed to be relatively small. U.S. CO_2 emission estimates from fossil fuel combustion are considered accurate within one or two percent. See, for example, Marland and Pippin (1990).

Stationary Source Fossil Fuel Combustion (excluding CO_2)

Stationary sources encompass all fossil fuel combustion activities except transportation (i.e., mobile combustion). Other than carbon dioxide (CO_2), which was addressed in the previous section, gases from stationary combustion include the greenhouse gases methane (CH_4) and nitrous oxide (N_2O) and the criteria pollutants nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Emissions of these gases from stationary sources depend upon fuel characteristics, technology type, usage of pollution control equipment, and ambient environmental conditions. Emissions also vary with the size and vintage of the combustion technology as well as maintenance and operational practices.

Stationary combustion is a small source of CH_4 and N_2O in the United States. Methane emissions from stationary combustion in 1996 accounted for less than 2 percent of total U.S. CH_4 emissions, while N_2O emissions from stationary combustion accounted for just under 4 percent of all N_2O emissions. Emissions of CH_4 increased slightly (from 2.3 to 2.5 MMTCE) over the period 1990 to 1996, due mainly to an increase in residential wood use. Nitrous oxide emissions rose 9 percent from 3.7 MMTCE in 1990 to 4.0 MMTCE in 1996. The largest source of N_2O emissions was coal combustion by electric utilities, which alone accounted for 55 percent of total N_2O emissions from stationary combustion in 1996.

Nitrous oxide and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion and the use of emission controls; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up and shut-down and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). Methane and NMVOC emissions from stationary combustion are believed to be a function of the CH_4 content of the fuel and post-combustion controls.

In general, stationary combustion was a significant source of NO_x and CO emissions, and a smaller source of NMVOCs. In 1996, emissions of NO_x from stationary combustion represented 45 percent of national NO_x emissions, while CO and NMVOC emissions from stationary combustion contributed approximately 7 and 6 percent, respectively, to the national totals for the same year. From 1990 to 1996, emissions of NO_x decreased by 4 percent, while emissions of CO and NMVOCs increased by 8 and 7 percent, respectively.

The increase in CO and NMVOC emissions from 1990 to 1996 can largely be attributed to increased residential wood consumption, which is the most significant source of these pollutants in the Energy sector. A combination of technological advances and more stringent emissions requirements dampened the rate of increase in these emissions. Overall, NO_x emissions from energy varied due to fluctuations in emissions from electric utilities, which constituted 58 percent of stationary NO_x emissions in 1996. Table 2-7, Table 2-8, Table 2-9, and Table 2-10 provide CH_4 and N_2O emission estimates from mobile sources by vehicle type, fuel type, and transport activity. Estimates of NO_x, CO, and NMVOC emissions in 1996 are given in Table 2-11.[3]

Methodology

Methane and nitrous oxide emissions were estimated by multiplying emission factors (by sector and fuel type) by fossil fuel and wood consumption data. Greenhouse gas emissions from stationary combustion activi-

3 See Annex B for a complete time series of criteria pollutant emission estimates for 1990 through 1996.

Table 2-7: CH_4 Emissions from Stationary Sources (MMTCE)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996
Electric Utilities	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	+	+	+	+	+	+	+
Natural gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Industrial	**0.7**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**
Coal	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Wood	0.3	0.2	0.3	0.3	0.3	0.3	0.3
Commercial/Institutional	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	+	+	+	+	+	+
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	+	+	+	0.1	0.1	0.1	0.1
Residential	**1.3**	**1.3**	**1.4**	**1.2**	**1.2**	**1.3**	**1.3**
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	1.1	0.9	0.9	1.0	1.0
Total	**2.3**	**2.3**	**2.4**	**2.3**	**2.3**	**2.4**	**2.5**

\+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.

Table 2-8: N_2O Emissions from Stationary Sources (MMTCE)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996
Electric Utilities	**2.0**	**2.0**	**2.0**	**2.1**	**2.1**	**2.1**	**2.2**
Coal	1.9	1.9	1.9	2.0	2.0	2.0	2.1
Fuel Oil	0.1	0.1	+	0.1	+	+	+
Natural gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Industrial	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**	**1.4**	**1.4**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	0.4	0.4	0.4	0.4	0.5	0.4	0.5
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.5	0.5	0.5	0.5	0.5	0.5	0.6
Commercial/Institutional	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	+	+	+
Natural gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Residential	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**3.7**	**3.7**	**3.7**	**3.8**	**3.8**	**3.8**	**4.0**

\+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.

Table 2-9: CH_4 Emissions from Stationary Sources (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996
Electric Utilities	**23**	**23**	**22**	**23**	**23**	**22**	**23**
Coal	16	16	16	17	17	17	18
Fuel Oil	4	4	3	3	3	2	2
Natural gas	3	3	3	3	3	3	3
Wood	+	+	+	+	+	+	+
Industrial	**129**	**126**	**130**	**132**	**136**	**138**	**142**
Coal	27	26	25	25	25	24	23
Fuel Oil	17	16	17	17	18	17	18
Natural gas	40	41	43	45	46	48	49
Wood	44	44	45	46	48	48	51
Commercial/Institutional	**31**	**31**	**31**	**35**	**35**	**36**	**38**
Coal	1	1	1	1	1	1	1
Fuel Oil	9	9	8	8	8	8	8
Natural gas	13	13	14	14	14	15	16
Wood	9	9	9	13	13	13	14
Residential	**218**	**227**	**237**	**211**	**207**	**223**	**226**
Coal	19	17	17	17	17	16	16
Fuel Oil	13	13	13	14	13	14	14
Natural Gas	21	22	23	24	24	24	26
Wood	166	175	184	156	153	170	170
Total	**401**	**407**	**420**	**402**	**401**	**420**	**429**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 2-10: N_2O Emissions from Stationary Sources (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996
Electric Utilities	**24**	**23**	**24**	**25**	**25**	**25**	**26**
Coal	23	22	23	24	24	24	25
Fuel Oil	1	1	1	1	1	+	+
Natural gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Industrial	**16**	**15**	**16**	**16**	**16**	**16**	**17**
Coal	4	4	3	3	3	3	3
Fuel Oil	5	5	5	5	5	5	6
Natural gas	1	1	1	1	1	1	1
Wood	6	6	6	6	6	6	7
Commercial/Institutional	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+
Fuel Oil	1	1	+	+	+	+	+
Natural gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Residential	**3**	**4**	**4**	**3**	**3**	**4**	**4**
Coal	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1
Natural Gas	+	+	+	+	+	+	1
Wood	2	2	2	2	2	2	2
Total	**44**	**43**	**44**	**45**	**45**	**45**	**47**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 2-11: 1996 Emissions of NO_x, CO, and NMVOC from Stationary Sources (Gg)

Sector/Fuel Type	NO_x	CO	NMVOCs
Electric Utilities	**5,473**	**341**	**41**
Coal	5,004	238	28
Fuel Oil	87	10	3
Natural gas	244	40	2
Wood	NA	NA	NA
Internal Combustion	137	53	9
Industrial	**2,875**	**972**	**188**
Coal	543	90	5
Fuel Oil	223	65	11
Natural gas	1,212	316	66
Wood	NA	NA	NA
Other Fuels[a]	113	277	46
Internal Combustion	784	224	60
Commercial/Institutional	**366**	**227**	**21**
Coal	35	14	1
Fuel Oil	93	17	3
Natural gas	212	49	10
Wood	NA	NA	NA
Other Fuels[a]	26	148	8
Residential	**804**	**3,866**	**724**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	44	3,621	687
Other Fuels[a]	760	244	37
Total	**9,518**	**5,407**	**975**

NA (Not Available)
Note: Totals may not sum due to independent rounding. See Annex B for emissions in 1990 through 1995.
[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1997).
[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1997).

ties were grouped into four sectors: industrial, commercial/institutional, residential, and electric utilities. For CH_4 and N_2O, estimates were based on consumption of coal, natural gas, fuel oil, and wood.

For NO_x, CO, and NMVOCs, the major source categories included in this section are those used in EPA (1997): coal, fuel oil, natural gas, wood, other fuels (including LPG, coke, coke oven gas, and others), and stationary internal combustion. The EPA also estimates emissions of NO_x, CO, and NMVOCs by sector and fuel source using a "bottom-up" estimating procedure. In other words, emissions were calculated either for individual sources (e.g., industrial boilers) or for multiple sources combined, using basic activity data as indicators of emissions. Depending on the source category, these basic activity data may include fuel consumption, fuel deliveries, tons of refuse burned, raw material processed, etc.

The EPA derived the overall emission control efficiency of a source category from published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary source combustion, as described above, is similar to the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

More detailed information on the methodology for calculating emissions from stationary sources including emission factors and activity data is provided in Annex B.

Data Sources

Emissions estimates for NO_x, CO, and NMVOCs in this section were taken directly from the EPA's *National Air Pollutant Emissions Trends: 1900 - 1996* (EPA 1997). U.S. energy data were provided by the U.S. Energy Information Administration's *Monthly Energy Review* (EIA 1997). Emission factors were provided by *the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997).

Uncertainty

Methane emission estimates from stationary sources are highly uncertain, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control). The uncertainties associated with the emission estimates of these gases are greater than with estimates of CO_2 from fossil fuel combustion, which are mainly a function of the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the criteria pollutants, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and projections of growth.

Mobile Source Fossil Fuel Combustion (excluding CO_2)

Mobile sources emit greenhouse gases other than CO_2, including methane (CH_4), nitrous oxide (N_2O), and the criteria pollutants carbon monoxide (CO), nitrogen oxides (NO_x), and non-methane volatile organic compounds (NMVOCs).

As with combustion in stationary sources, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, and combustion temperatures, as well as usage of pollution control equipment. Nitrous oxide, in particular, can be formed by the catalytic processes used to control NO_x and CO emissions. Carbon monoxide emissions from mobile source combustion are significantly affected by combustion efficiency and presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. This occurs especially in idle, low speed and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.

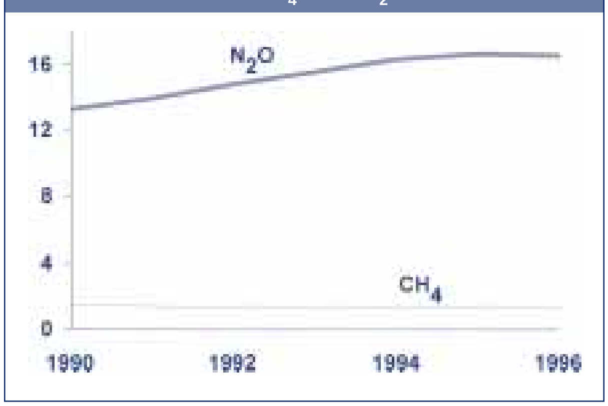
Emissions from mobile sources were estimated by transport mode (e.g., road, air, rail, and water) and fuel type—motor gasoline, diesel fuel, jet fuel, aviation gas, natural gas, liquefied petroleum gas (LPG), and residual fuel oil—and vehicle type. Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile source emissions. Table 2-12, Table 2-13, Table 2-14, and Table 2-15 provide CH_4 and N_2O emission estimates from mobile sources by vehicle type, fuel type, and transport mode. Estimates of NO_x, CO, and NMVOC emissions in 1996 are given in Table 2-16.[4]

Mobile sources were responsible for a small portion of national CH_4 emissions but were the second largest source of N_2O in the United States. From 1990 to 1996, CH_4 emissions declined by 7 percent, to 1.4 MMTCE. Nitrous oxide emissions, however, rose from 13.2 to 16.5 MMTCE (a 25 percent increase). The reason for this conflicting trend was that the control technologies employed on highway vehicles in the United States lowered CO, NO_x, NMVOC, and CH_4 emissions, but resulted in higher N_2O emission rates. Fortunately, since 1994 improvements in the emission control technologies installed on new vehicles have reduced emission rates of both NO_x and N_2O per vehicle mile traveled. Overall, CH_4 and N_2O emissions were dominated by gasoline-fueled passenger cars and light-duty gasoline trucks. From 1995 to 1996, both CH_4 and N_2O emissions were almost constant (see Figure 2-7).

Emissions of criteria pollutants as a whole increased from 1990 through 1994, after which there was a slight decrease through 1996. A drop in gasoline prices combined with a strengthening U.S. economy caused the initial increase. These factors pushed the vehicle miles traveled (VMT) by road sources up, resulting in increased fuel consumption and higher emissions. Some of this increased activity was offset by an increasing portion of the U.S. vehicle fleet meeting established emissions standards.

Figure 2-7

Mobile Source CH_4 and N_2O Emissions



4 See Annex C for a complete time series of criteria pollutant emission estimates for 1990 through 1996.

Table 2-12: CH_4 Emissions from Mobile Sources (MMTCE)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996
Gasoline Highway	**1.3**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**
Passenger Cars	0.8	0.7	0.7	0.7	0.7	0.7	0.6
Light-Duty Trucks	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Heavy-Duty Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non-Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Boats and Vessels	0.1	0.1	0.1	+	+	+	+
Locomotives	+	+	+	+	+	+	+
Farm Equipment	+	+	+	+	+	+	+
Construction Equipment	+	+	+	+	+	+	+
Aircraft	+	+	+	+	+	+	+
Other*	+	+	+	+	+	+	+
Total	**1.5**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**

+ Does not exceed 0.05 MMTCE

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-13: N_2O Emissions from Mobile Sources (MMTCE)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996
Gasoline Highway	**12.3**	**12.9**	**13.8**	**14.6**	**15.3**	**15.6**	**15.5**
Passenger Cars	8.6	9.0	9.7	10.1	9.9	10.1	10.0
Light-Duty Trucks	3.4	3.7	3.9	4.2	5.1	5.2	5.1
Heavy-Duty Vehicles	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Motorcycles	+	+	+	+	+	+	+
Diesel Highway	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Non-Highway	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**
Boats and Vessels	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Farm Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction Equipment	+	+	+	+	+	+	+
Aircraft[a]	+	+	+	+	+	+	+
Other[b]	+	+	+	+	+	+	+
Total	**13.2**	**13.9**	**14.8**	**15.6**	**16.3**	**16.6**	**16.5**

+ Does not exceed 0.05 MMTCE

Note: Totals may not sum due to independent rounding.

[a] Aircraft emissions include aviation gasoline combustion and exclude jet fuel combustion due to insufficient data availability.

[b] "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-14: CH_4 Emissions from Mobile Sources (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996
Gasoline Highway	**220**	**214**	**211**	**209**	**211**	**209**	**203**
Passenger Cars	133	128	127	123	115	114	111
Light-Duty Trucks	67	66	65	66	75	74	71
Heavy-Duty Vehicles	16	16	15	16	17	17	16
Motorcycles	4	4	4	4	4	4	4
Diesel Highway	**10**	**10**	**10**	**11**	**11**	**11**	**12**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Heavy-Duty Vehicles	10	10	10	10	11	11	11
Non-Highway	**25**	**25**	**26**	**23**	**24**	**24**	**24**
Boats and Vessels	9	10	10	8	8	9	8
Locomotives	3	2	3	2	2	3	3
Farm Equipment	6	5	6	5	6	6	6
Construction Equipment	1	1	1	1	1	1	1
Aircraft	6	6	6	5	5	5	6
Other*	1	1	1	1	1	1	1
Total	**255**	**250**	**248**	**244**	**246**	**244**	**238**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-15: N_2O Emissions from Mobile Sources (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996
Gasoline Highway	**145**	**153**	**164**	**173**	**181**	**184**	**183**
Passenger Cars	102	107	115	120	117	119	119
Light-Duty Trucks	41	44	46	50	60	61	61
Heavy-Duty Vehicles	2	3	3	3	3	4	4
Motorcycles	+	+	+	+	+	+	+
Diesel Highway	**6**	**6**	**6**	**6**	**7**	**7**	**7**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Heavy-Duty Vehicles	5	5	6	6	6	6	6
Non-Highway	**5**	**6**	**6**	**5**	**5**	**5**	**5**
Boats and Vessels	3	3	3	2	2	3	2
Locomotives	1	1	1	1	1	1	1
Farm Equipment	1	1	1	1	1	1	1
Construction Equipment	+	+	+	+	+	+	+
Aircraft[a]	+	+	+	+	+	+	+
Other[b]	1	+	+	+	1	+	+
Total	**157**	**165**	**175**	**184**	**193**	**196**	**195**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

[a] Aircraft emissions includes aviation gasoline combustion and excludes jet fuel combustion due to insufficient data availability.

[b] "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-16: 1996 Emissions of NO_x, CO, and NMVOC from Mobile Sources (Gg)

Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,752**	**46,712**	**4,709**
Passenger Cars	3,075	29,883	2,979
Light-Duty Trucks	1,370	13,377	1,435
Heavy-Duty Vehicles	295	3,267	259
Motorcycles	12	185	35
Diesel Highway	**1,753**	**1,318**	**283**
Passenger Cars	35	30	12
Light-Duty Trucks	9	7	4
Heavy-Duty Vehicles	1,709	1,280	267
Non-Highway	**4,183**	**15,424**	**2,201**
Boats and Vessels	244	1,684	460
Locomotives	836	102	44
Farm Equipment	1,012	901	207
Construction Equipment	1,262	1,066	184
Aircraft	151	861	161
Other*	678	10,810	1,144
Total	**10,688**	**63,455**	**7,192**

Note: Totals may not sum due to independent rounding. See Annex C for emissions in 1990 through 1995.
* "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Fossil-fueled motor vehicles comprise the single largest source of CO emissions in the United States and are a significant contributor to NO_x and NMVOC emissions. In 1996, CO emissions from mobile sources contributed 83 percent of all U.S. CO emissions and 50 and 42 percent of NO_x and NMVOC emissions, respectively. Since 1990, emissions of CO and NMVOCs from mobile sources decreased by 5 and 10 percent, respectively, while emissions of NO_x increased by 1 percent.

Methodology

Estimates for CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each category. Depending upon the category, activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT). Emission estimates from highway vehicles were based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Fuel consumption data was employed as a measure of activity for non-highway vehicles and then fuel-specific emission factors were applied. A complete discussion of the methodology used to estimate emissions from mobile sources is provided in Annex C.

The EPA provided emissions estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles[5], aircraft, and seven categories of off-highway vehicles[6].

Data Sources

Emission factors used in the calculations of CH_4 and N_2O emissions are presented in Annex C. The *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) provided emission factors for CH_4, and were developed using MOBILE5a, a model used by the Environmental Protection Agency (EPA) to estimate exhaust and running loss emissions from highway vehicles. The MOBILE5a model uses information on ambient temperature, vehicle speeds, national vehicle registration distributions, gasoline volatility, and other variables in order to produce these factors (EPA 1997b).

Emission factors for N_2O from gasoline highway vehicles came from a recent EPA report (1998). This report developed emission factors for older passenger cars (roughly pre-1992 in California and pre-1994 in the rest of the United States), from published references, and for newer cars from a recent testing program at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL). These emission factors for gasoline highway vehicles are lower than the U.S. default values in the *Revised 1996 IPCC Guidelines*, but are higher than the European de-

[5] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[6] These categories included: gasoline and diesel farm tractors, other gasoline and diesel farm machinery, gasoline and diesel construction equipment, snowmobiles, small gasoline utility engines, and heavy-duty gasoline and diesel general utility engines.

fault values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. default values in the *Revised 1996 IPCC Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test protocols. More details may be found in EPA (1998).

Emission factors for gasoline vehicles other than passenger cars were scaled from those for passenger cars with the same control technology, based on their relative fuel economy. This scaling was supported by limited data showing that light-duty trucks emit more N_2O than passenger cars with equivalent control technology. The use of fuel-consumption ratios to determine emission factors is considered a temporary measure only, to be replaced as soon as additional testing data are available. For more details, see U.S. EPA (1998). Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). There is little data addressing N_2O emissions from U.S. diesel-fueled vehicles, and in general, European countries have had more experience with diesel-fueled vehicles. U.S. default values in the *Revised 1996 IPCC Guidelines* were used for non-highway vehicles.

Activity data were gathered from several U.S. government sources including EIA (1997), FHWA (1997), and FAA (1997). Control technology data for highway vehicles were obtained from the EPA's Office of Mobile Sources. Annual VMT data for 1990 through 1996 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database, as noted in EPA (1997a).

Emissions estimates for NO_x, CO, NMVOCs were taken directly from the EPA's *National Air Pollutant Emissions Trends, 1900 - 1996* (EPA 1997a).

Uncertainty

Mobile source emission estimates can vary significantly due to assumptions concerning fuel type and composition, technology type, average speeds, type of emission control equipment, equipment age, and operating and maintenance practices. Fortunately, detailed activity data for mobile sources were available, including VMT by vehicle type for highway vehicles. The allocation of this VMT to individual model years was done using the profile of U.S. vehicle usage by vehicle age in 1990 as specified in MOBILE 5a. Data to develop a temporally variable profile of vehicle usage by model year instead of age was not available.

Average emission factors were developed based on numerous assumptions concerning the age and model of vehicle; percent driving in cold start, warm start, and cruise conditions; average driving speed; ambient temperature; and maintenance practices. The factors for regulated emissions from mobile sources—CO, NO_x, and hydrocarbons—have been extensively researched, and so involve lower uncertainty than emissions of unregulated gases. Although methane has not been singled out for regulation in the United States, overall hydrocarbon emissions from mobile sources—a component of which is methane—are regulated.

Compared to methane, CO, NO_x, and NMVOCs, there is relatively little data available to estimate emission factors for nitrous oxide. Nitrous oxide is not a criteria pollutant, and measurements of it in automobile exhaust have not been routinely collected. Research data has shown that N_2O emissions from vehicles with catalytic converters are greater than those without emission controls, and that vehicles with aged catalysts emit more than new ones. The emission factors used were, therefore, derived from aged cars (EPA 1998). The emission factors used for Tier 0 and older cars were based on tests of 28 vehicles; those for newer vehicles were based on tests of 22 vehicles. This sample is small considering that it is being used to characterize the entire U.S. fleet, and the associated uncertainty is therefore large. Currently, N_2O gasoline highway emission factors for vehicles other than passenger cars are scaled based on those for passenger cars and their relative fuel economy. Actual measurements should be substituted for this procedure when they become available. Further testing is needed to reduce the uncertainty in emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Emissions of N_2O from the combustion of jet fuel in aircraft were not estimated due to insufficient data availability on the number of landing and take-off cycles executed and cruising fuel consumption by specific type of aircraft. The estimates presented for N_2O emissions from aircraft include only the combustion of aviation gasoline. Complete N_2O emission estimates from aircraft will be included in future inventories.

Overall, uncertainty for N_2O emissions estimates is considerably higher than for CH_4, CO, NO_x, or NMVOC; however, all these gases involve far more uncertainty than CO_2 emissions from fossil fuel combustion.

Coal Mining

All underground and surface coal mining liberates (i.e., releases) methane as part of normal operations. The amount of methane liberated during mining is primarily dependent upon the amount of methane stored in the coal and the surrounding strata. This *in situ* methane content is a function of the quantity of methane generated during the coal formation process and its ability to migrate through the surrounding strata over time. The degree of coalification—defined by the rank or quality of the coal formed—determines the amount of methane generated during the coal formation process; higher ranked coals generate more methane. The amount of methane that remains in the coal and surrounding strata also depends upon geologic characteristics such as pressure and temperature within a coal seam. Deeper coal deposits tend to retain more of the methane generated during coalification. Accordingly, deep underground coal seams generally have higher methane contents than shallow coal seams or surface deposits.

Underground, versus surface, coal mines contribute the largest share of methane emissions. All underground coal mines employ ventilation systems to ensure that methane levels remain within safe concentrations. These systems exhaust significant amounts of methane to the atmosphere in low concentrations. Additionally, over twenty gassy U.S. coal mines supplement ventilation with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of methane before or after mining. Currently, twelve coal mines collect methane from degasification systems and sell this gas to a pipeline, thus reducing emissions to the atmosphere. Surface coal mines also release methane as the overburden is removed and the coal is exposed. Additionally, after coal has been mined, small amounts of methane retained in the coal are released during processing, storage, and transport.

Total methane emissions in 1996 were estimated to be 18.9 MMTCE (3.3 Tg), declining from 24.0 MMTCE (4.2 Tg) in 1990 (see Table 2-17 and Table 2-18). Of this amount, underground mines accounted for 67 percent, surface mines accounted for 13 percent, and post-mining emissions accounted for 20 percent. With the exception of 1995, total methane emissions declined every year during this period. In 1993, emissions from underground mining dropped to a low of 2.8 Tg, primarily due to labor strikes at many of the large underground mines. In 1995, there was an increase in methane emissions from underground mining (3.1 Tg) due to particularly high emissions at the gassiest coal mine in the country. While methane liberated from underground mines fluctuated from 1990 to 1996, the amount of methane recovered and used increased. As a result, with the exception of 1995, total methane emitted from underground mines declined in each year. Surface mine emissions

Table 2-17: Methane Emissions from Coal Mining (MMTCE)

Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Underground Mining	17.1	16.4	15.6	13.3	13.1	14.2	12.6
Liberated	18.8	18.1	17.8	16.0	16.3	17.7	16.5
Recovered & Used	(1.6)	(1.7)	(2.1)	(2.7)	(3.2)	(3.4)	(3.8)
Surface Mining	2.8	2.6	2.6	2.5	2.6	2.4	2.5
Post- Mining (Underground)	3.6	3.4	3.3	3.0	3.3	3.3	3.4
Post-Mining (Surface)	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Total	**24.0**	**22.8**	**22.0**	**19.2**	**19.4**	**20.3**	**18.9**

Note: Totals may not sum due to independent rounding.

Table 2-18: Methane Emissions from Coal Mining (Tg)

Activity	1990	1991	1992	1993	1994	1995	1996
Underground Mining	3.0	2.9	2.7	2.3	2.3	2.5	2.2
Liberated	3.3	3.2	3.1	2.8	2.8	3.1	2.9
Recovered & Used	(0.3)	(0.3)	(0.4)	(0.5)	(0.6)	(0.6)	(0.7)
Surface Mining	0.5	0.4	0.4	0.4	0.5	0.4	0.4
Post- Mining (Underground)	0.6	0.6	0.6	0.5	0.6	0.6	0.6
Post-Mining (Surface)	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.2**	**4.0**	**3.8**	**3.4**	**3.4**	**3.6**	**3.3**

Note: Totals may not sum due to independent rounding.

and post-mining emissions remained relatively constant from 1990 to 1996.

In 1994, EPA's Coalbed Methane Outreach Program (CMOP) began working with the coal industry and other stakeholders to identify and remove obstacles to investments in coal mine methane recovery and use projects. Reductions attributed to CMOP were estimated to be 0.7, 0.8, and 1.0 MMTCE in 1994, 1995, and 1996, respectively.

Methodology

The methodology for estimating methane emissions from coal mining consists of two main steps. The first step involved estimating methane emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involved estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin specific emissions factors.

Underground mines. Total methane emitted from underground mines was estimated as the quantity of methane liberated from ventilation systems, plus methane liberated from degasification systems, minus methane recovered and used. The Mine Safety and Heath Administration (MSHA) measures methane emissions from ventilation systems for all mines with detectable[7] methane concentrations. These mine-by-mine measurements were used to estimate methane emissions from ventilation systems.

Some of the gassier underground mines also use degasification systems (e.g., wells or boreholes) that remove methane before or after mining . This methane can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of methane collected by each of the more than twenty mines using these systems, depending on available data. For example, some mines have reported to EPA the amounts of methane liberated from their degasification systems. For mines that sell recovered methane to a pipeline, pipeline sales data was used to estimate degasification emissions. Finally, for those mines for which no other data was available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of methane recovered by degasification systems and then used (i.e., not vented) was estimated. This calculation was complicated by the fact that methane is rarely recovered and used during the same year in which the particular coal seam is mined. In 1996, twelve coal mines sold recovered methane to a pipeline operator. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies, and information supplied by coal mine operators regarding the number of years in advance of mining that gas recovery occurred. Additionally, some of the state agencies provided individual well production information, which was used to assign gas sales to a particular year.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining methane emissions were estimated by multiplying basin-specific coal production by basin-specific emissions factors. For surface mining, emissions factors were developed by assuming that surface mines emit

[7] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

from one to three times as much methane as the average *in situ* methane content of the coal. This accounts for methane released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be from 25 to 40 percent of the average *in situ* methane content of coals mined in the basin.

Data Sources

The Mine Safety and Health Administration provided mine-specific information on methane liberated from ventilation systems at underground mines. EPA developed estimates of methane liberated from degasification systems at underground mines based on available data for each of the mines employing these systems. The primary sources of data for estimating emissions avoided at underground mines were gas sales data published by state petroleum and natural gas agencies and information supplied by mine operators regarding the number of years in advance of mining that gas recovery occurred. Annual coal production data was taken from the Energy Information Agency's *Coal Industry Annual* (see Table 2-19) (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997). Data on *in situ* methane content and emissions factors were taken from EPA (1993).

Uncertainty

Table 2-19: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,247	546,814	931,061
1991	368,633	532,653	901,285
1992	368,625	534,286	902,911
1993	318,476	539,211	857,687
1994	362,063	575,525	937,588
1995	359,475	577,634	937,109
1996	371,813	593,311	965,125

The emission estimates from underground ventilation systems were based upon actual measurement data for mines with detectable methane emissions. Accordingly, the uncertainty associated with these measurements is estimated to be low. Estimates of methane liberated from degasification systems are less certain because EPA assigns default recovery efficiencies for a subset of U.S. mines. Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emissions factors from field measurements. Because underground emissions comprise the majority of total coal mining emissions, the overall uncertainty is estimated to be only ±15 percent.[8]

Natural Gas Systems

Methane emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas combusting engine and turbine exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions.

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, hundreds of thousands of miles of transmission pipelines, and over a million miles of distribution pipeline. The system, though, can be divided into four stages, each with different factors affecting methane emissions, as follows:

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, treatment facilities, gathering pipelines, and process units such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices accounted for the majority of emissions. Emissions from field production have increased absolutely and as a proportion of total emissions from natural gas systems—approximately 27 percent between 1990 and 1996—due to an increased number of producing gas wells and related equipment.

[8] Preliminary estimate

Processing. In this stage, processing plants remove various constituents from the raw gas before it is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, were the primary contributor from this stage. Processing plants accounted for about 12 percent of methane emissions from natural gas systems during the period of 1990 through 1996.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production areas to distribution centers or large volume customers. From 1990 to 1996, the reported length of the gas utility transmission pipeline varied, with an overall decline from about 280,000 miles to about 265,000 miles. Throughout the transmission system, compressor stations pressurize the gas to move it through the pipeline. Fugitive emissions from compressor stations and metering and regulating stations accounted for the majority of the emissions from transmission. Pneumatic devices and engine exhaust were smaller sources of emissions from transmission facilities. Methane emissions from the transmission stage accounted for approximately 35 percent of the emissions from natural gas systems. Natural gas is also injected and stored in underground formations during periods of low demand, and withdrawn, processed, and distributed during periods of high demand. Compressors and dehydrators were the primary contributors from these storage facilities. Less than one percent of total emissions from natural gas systems can be attributed to these facilities.

Distribution. The distribution of natural gas requires the use of low-pressure pipelines to deliver gas to customers. The distribution network consisted of nearly 1.5 million miles of pipeline in 1996, increasing from a 1990 figure of just over 1.3 million miles (AGA 1996). Distribution system emissions, which accounted for approximately 27 percent of emissions from natural gas systems, resulted mainly from fugitive emissions from gate stations and non-plastic piping. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.

Overall, natural gas systems emitted 34.1 MMTCE (6.0 Tg) of methane in 1996 or 19 percent of total methane emissions (see Table 2-20 and Table 2-21). Emissions rose slightly from 1990 to 1996, reflecting an increase in the number of producing gas wells and miles of distribution pipeline. Initiated in 1993, EPA's Natural Gas STAR program is working with the gas industry to promote profitable

Table 2-20: Methane Emissions from Natural Gas Systems (MMTCE)

Stage	1990	1991	1992	1993	1994	1995	1996
Field Production	8.0	8.1	8.5	8.7	8.8	9.1	9.5
Processing	4.0	4.0	4.0	4.0	4.2	4.1	4.1
Transmission and Storage	12.6	12.7	12.9	12.6	12.5	13.2	12.4
Distribution	8.3	8.4	8.6	8.8	8.7	8.7	9.1
Total	**32.9**	**33.3**	**33.9**	**34.1**	**33.9**	**34.6**	**34.1**

Note: 1994 through 1996 totals include reductions from Natural Gas STAR program. Totals may not sum due to independent rounding.

Table 2-21: Methane Emissions from Natural Gas Systems (Tg)

Stage	1990	1991	1992	1993	1994	1995	1996
Field Production	1.4	1.4	1.5	1.5	1.5	1.5	1.5
Processing	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Transmission and Storage	2.2	2.2	2.3	2.2	2.2	2.3	2.2
Distribution	1.4	1.5	1.5	1.5	1.5	1.5	1.6
Total	**5.7**	**5.8**	**5.9**	**5.9**	**5.9**	**6.0**	**6.0**

Note: 1994 through 1996 totals include reductions from Natural Gas STAR program. Totals may not sum due to independent rounding.

practices that reduce methane emissions. The program was estimated to have reduced emissions by 0.3, 0.5, and 0.9 MMTCE in 1994, 1995, and 1996, respectively.

Methodology

The foundation for the estimate of methane emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (GRI/EPA 1995). The GRI/EPA study developed over 100 detailed emission factors and activity levels through site visits to selected gas facilities, and arrived at a national point estimate for 1992. Since publication of this study, EPA conducted additional analysis to update the activity data for some of the components of the system, particularly field production equipment. Summing emissions across individual sources in the natural gas system provided a 1992 baseline emissions estimate from which the emissions for the period 1990 through 1996 were derived.

Apart from the year 1992, detailed statistics on each of the over 100 activity levels were not available for the time series 1990 through 1996. To estimate these activity levels, aggregate annual statistics were obtained on the main driving variables, including: number of producing wells, number of gas plants, miles of transmission pipeline, miles of distribution pipeline, and miles of distribution services. By assuming that the relationships among these variables remained constant (e.g., the number of heaters per well remained the same), the statistics on these variables formed the basis for estimating other activity levels.

For the period 1990 through 1995, the emission factors were held constant. A gradual improvement in technology and practices is expected to reduce the emission factors slightly over time. To reflect this trend, the emission factors for 1996 were reduced by about 0.2 percent, a rate that, if continued, would lower the emission factors by 5 percent in 2020. See Annex E for more detailed information on the methodology and data used to calculate methane emissions from natural gas systems.

Data Sources

Activity data were taken from the American Gas Association (AGA 1991, 1992, 1993, 1994, 1995, 1996, 1997), the Energy Information Administration's *Annual Energy Outlook* (EIA 1997a) and *Natural Gas Annual* (EIA 1997b), and the Independent Petroleum Association of America (IPAA 1997). The U.S. Department of Interior (DOI 1997) supplied offshore platform data. All emission factors were taken from GRI/EPA (1995).

Uncertainty

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. Despite the difficulties associated with estimating emissions from this source, the uncertainty in the total estimated emissions are believed to be on the order of ±40 percent.

Petroleum Systems

One of the gases emitted from the production and refining of petroleum products is methane. The activities that lead to methane emissions include: production field treatment and separation, routine maintenance of production field equipment, crude oil storage, refinery processes, crude oil tanker loading and unloading, and venting and flaring. Each stage is described below:

Production Field Operations. Fugitive emissions from oil wells and related production field treatment and separation equipment are the primary source of emissions from production fields. From 1990 to 1996, these emissions accounted for about 10 percent of total emissions from petroleum systems. Routine maintenance, which includes the repair and maintenance of valves, piping, and other equipment, accounted for less than 1 percent of total emissions from petroleum systems. Emissions from production fields are expected to decline in the future as the number of oil wells decreases.

Crude Oil Storage. Crude oil storage tanks emit methane during two processes. "Breathing losses" from roof seals and joints occur when the tank is in use, and while tanks are being drained or filled, "working losses" occur as the methane in the air space above the liquid is displaced. Piping and other equipment at storage facilities can also produce fugitive emissions. Between 1990 and 1996, crude oil storage emissions accounted for less than 1 percent of total emissions from petroleum systems.

Refining. Waste gas streams from refineries are a source of methane emissions. Based on Tilkicioglu and Winters (1989), who extrapolated waste gas stream emissions to national refinery capacity, emissions estimates from this source accounted for approximately 4 percent of total methane emissions from the production and refining of petroleum.

Tanker Operations. The loading and unloading of crude oil tankers releases methane. From 1990 to 1996, emissions from crude oil transportation on tankers accounted for roughly 2 percent of total emissions from petroleum systems.

Venting and Flaring. Gas produced during oil production that cannot be contained or otherwise used is released into the atmosphere or flared. Vented gas typically has a high methane content; however, it is assumed that flaring destroys the majority of the methane in the gas (about 98 percent depending upon the moisture content of the gas). Venting and flaring may account for up to 85 percent of emissions from petroleum systems. There is considerable uncertainty in the estimate of emissions from this activity.

From 1990 to 1996, methane emissions from petroleum systems remained relatively constant at approximately 1.6 MMTCE (0.3 Tg), accounting for about 1 percent of total methane emissions in 1996. Emission estimates are provided below in Table 2-22 and Table 2-23.

Methodology

The methodology used for estimating emissions from each activity is described below:

Production Field Operations. Emission estimates were calculated by multiplying emission factors (i.e., emissions per oil well) with their corresponding activity data (i.e., number of oil wells). To estimate emissions for 1990 to 1996, emission factors developed to estimate 1990 emissions were multiplied by updated activity data for 1990 through 1996. Emissions estimates from petroleum systems excluded associated natural gas wells to prevent double counting with the estimates for natural gas systems.

Crude Oil Storage. Tilkicioglu and Winters (1989) estimated crude oil storage emissions on a model tank farm facility with fixed and floating roof tanks. Emission factors developed for the model facility were applied to published crude oil storage data to estimate emissions.

Table 2-22: Methane Emissions from Petroleum Systems (MMTCE)

Stage	1990	1991	1992	1993	1994	1995	1996
Production Field Operations	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Crude Oil Storage	+	+	+	+	+	+	+
Refining	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Tanker Operations	+	+	+	+	+	+	+
Venting and Flaring	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.5**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.

Table 2-23: Methane Emissions from Petroleum Systems (Gg)

Stage	1990	1991	1992	1993	1994	1995	1996
Production Field Operations	24	25	24	24	24	23	23
Crude Oil Storage	2	2	2	2	2	2	2
Refining	10	10	10	10	10	10	9
Tanker Operations	6	6	5	5	5	5	5
Venting and Flaring	231	231	231	231	231	231	231
Total	**272**	**273**	**272**	**272**	**272**	**271**	**271**

Note: Totals may not sum due to independent rounding.

Refining. Tilkicioglu and Winters (1989) also estimated methane emissions from waste gas streams based on measurements at ten refineries. These data were extrapolated to total U.S. refinery capacity to estimate emissions from refinery waste gas streams for 1990. To estimate emissions for 1991 through 1996, the emissions estimates for 1990 were scaled using updated data on U.S. refinery capacity.

Tanker Operations. Methane emissions from tanker operations are associated with the loading and unloading of domestically-produced crude oil transported by tanker, and the unloading of foreign-produced crude transported by tanker. The quantity of domestic crude transported by tanker was estimated as Alaskan crude oil production less Alaskan refinery crude utilization, plus 10 percent of non-Alaskan crude oil production. Crude oil imports by tanker were estimated as total imports less imports from Canada. An emission factor based on the methane content of hydrocarbon vapors emitted from crude oil was employed (Tilkicioglu and Winters 1989). This emission factor was multiplied by updated activity data to estimate total emissions for 1990 through 1996.

Venting and Flaring. Although venting and flaring data indicate that the amount of venting and flaring activity has changed over time, there is currently insufficient data to assess the change in methane emissions associated with these changes. Given the considerable uncertainty in the emissions estimate for this stage, and the inability to discern a trend in actual emissions, the 1990 emissions estimate was held constant for the years 1991 through 1996.

See Annex F for more detailed information on the methodology and data used to calculate methane emissions from petroleum systems.

Data Sources

Data on the number of oil wells in production fields were taken from the American Petroleum Institute (API 1997) as were the number of oil wells that do not produce natural gas. Crude oil storage, U.S. refinery capacity, crude oil stocks, crude oil production, utilization, and import data were obtained from the U.S. Department of Energy (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997). Emission factors were taken from Tilkicioglu and Winters (1989) and EPA (1993).

Uncertainty

There are significant uncertainties associated with all aspects of the methane emissions estimates from petroleum systems. Published statistics are inadequate for estimating activity data at the level of detail required. Similarly, emission factors for each stage remain uncertain. In particular, there is insufficient information to estimate annual venting and flaring emissions using published statistics. EPA is currently undertaking more detailed analyses of emissions from this source and anticipates that new information will be available for the 1997 inventory. Preliminary work suggests that emissions will increase. Table 2-24 provides emission estimate ranges given the uncertainty in the venting and flaring estimates.

Natural Gas Flaring and Criteria Pollutant Emissions from Oil and Gas Activities

The flaring of natural gas from petroleum wells is a small source of carbon dioxide (CO_2). In addition, oil and gas activities also release small amounts of nitrogen oxides (NO_x), carbon monoxide (CO), and nonmethane

Table 2-24: Uncertainty in Methane Emissions from Petroleum Systems (Gg)

Stage	1990	1991	1992	1993	1994	1995	1996
Venting and Flaring (point estimate)	**231**	**231**	**231**	**231**	**231**	**231**	**231**
Low	93	93	93	93	93	93	93
High	462	462	462	462	462	462	462
Total (point estimate)	**272**	**273**	**272**	**272**	**272**	**271**	**271**
Low	103	103	103	103	103	102	102
High	627	631	628	627	625	621	620

volatile organic compounds (NMVOCs). Each of these sources is a small portion of overall emissions. Emissions of CO_2, NO_x, and CO from petroleum and natural gas production activities are all less than 1 percent of national totals, while NMVOC emissions are roughly 3 percent of national totals.

Carbon dioxide emissions from petroleum production result from natural gas that is flared (i.e., combusted) at the production site. Barns and Edmonds (1990) noted that of total reported U.S. venting and flaring, approximately 20 percent is actually vented, with the remaining 80 percent flared. For 1996, these emissions were estimated to be approximately 3.5 MMTCE (12.7 Tg), an increase of 75 percent from 1990 (see Table 2-25).

Criteria pollutant emissions from oil and gas production, transportation, and storage, constitute a relatively small and stable portion of the total emissions of these gases for the 1990 to 1996 period (see Table 2-26).

Table 2-25: CO_2 Emissions from Natural Gas Flaring

Year	MMTCE	Tg
1990	2.0	7.3
1991	2.2	8.2
1992	2.2	8.1
1993	3.0	11.0
1994	3.0	11.1
1995	3.7	13.7
1996	3.5	12.7

Table 2-26: NO_x, NMVOCs, and CO Emissions from Oil and Gas Activities (Gg)

Year	NO_x	CO	NMVOCs
1990	139	302	555
1991	110	313	581
1992	134	337	574
1993	111	337	588
1994	106	307	587
1995	100	316	582
1996	100	316	469

Methodology

The estimates for CO_2 emissions were prepared using an emission factor of 14.92 MMTCE/QBtu of flared gas, and an assumed flaring efficiency of 100 percent. The quantity of flared gas (i.e., 80 percent of total vented and flared gas) for each year was multiplied by this factor to calculate emissions.

Criteria pollutant emission estimates for NO_x, CO, and NMVOCs were determined using industry-published production data and applying average emission factors.

Data Sources

Activity data for estimating CO_2 emissions from natural gas flaring were provided in EIA's *Natural Gas Annual* (EIA 1997). The emission factor was also provided by EIA.

EPA (1997) provided emission estimates for NO_x, CO, and NMVOCs from petroleum refining, petroleum product storage and transfer, and petroleum marketing operations. Included are gasoline, crude oil and distillate fuel oil storage and transfer operations, gasoline bulk terminal and bulk plants operations, and retail gasoline service stations operations.

Uncertainty

Uncertainties in CO_2 emission estimates primarily arise from assumptions concerning what proportion of natural gas is flared and the flaring efficiency. The 20 percent vented as methane is accounted for in the section on methane emissions from petroleum production, refining, transportation, and storage activities. Uncertainties in criteria pollutant emission estimates are partly due to the accuracy of the emission factors used and projections of growth.

Wood Biomass and Ethanol Consumption

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates carbon dioxide (CO_2). However, in the long run the carbon dioxide emitted from biomass consumption does not increase atmospheric carbon dioxide concentrations, assuming the biogenic carbon emitted is offset by the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the

Table 2-27: CO_2 Emissions from Wood Consumption by End-Use Sector (MMTCE)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Electric Utility	0.3	0.2	0.2	0.2	0.2	0.2	0.3
Industrial	34.0	33.3	34.7	35.4	36.5	37.0	38.9
Residential	12.7	13.4	14.1	11.9	11.7	13.0	13.0
Commercial	0.7	0.7	0.7	1.0	1.0	1.0	1.1
Total	**47.6**	**47.5**	**49.7**	**48.6**	**49.4**	**51.2**	**53.2**

Note: Totals may not sum due to independent rounding.

Table 2-28: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996
Electric Utility	1.0	0.8	0.9	0.9	0.9	0.9	1.0
Industrial	124.8	122.1	127.3	129.8	133.7	135.7	142.6
Residential	46.4	49.0	51.5	43.8	42.9	47.6	47.5
Commercial	2.4	2.4	2.4	3.5	3.6	3.6	3.9
Total	**174.6**	**174.3**	**182.1**	**178.0**	**181.1**	**187.8**	**195.0**

Note: Totals may not sum due to independent rounding.

U.S. totals. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for under the Land-Use Change and Forestry sector.

In 1996, CO_2 emissions due to burning of woody biomass within the industrial, residential and commercial end-use sectors and by electric utilities were about 53.2 MMTCE (195.0 Tg) (see Table 2-27 and Table 2-28). As the largest consumer of biomass fuels, the industrial end-use sector was responsible for 73 percent of the CO_2 emissions from biomass-based fuels. The residential end-use sector was the second largest emitter, making up 24 percent of total emissions from woody biomass. The commercial end-use sector and electric utilities accounted for the remainder.

Between 1990 and 1996, total emissions of CO_2 from biomass burning increased 12 percent. This increase in emissions was mainly due to a 14 percent rise in industrial biomass fuel consumption between 1990 and 1996. Consumption of biomass fuels within the commercial end-use sector and by electric utilities remained relatively stable and thus had little impact on changes in overall CO_2 emissions from biomass combustion.

Biomass-derived fuel consumption in the United States consisted mainly of ethanol use in the transportation end-use sector. Ethanol is primarily produced from corn grown in the Midwest, and was used primarily in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. Ethanol and ethanol blends are believed to burn "cleaner" than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

In 1996, the United States consumed an estimated 74 trillion Btus of ethanol (1.0 billion gallons), mostly in the transportation end-use sector. Emissions of CO_2 in 1996 due to ethanol fuel burning were estimated to be approximately 1.4 MMTCE (5.1 Tg) (see Table 2-29). Between 1990 and 1991, emissions of CO_2 due to ethanol fuel consumption fell by 21 percent. Since this de-

Table 2-29: CO_2 Emissions from Ethanol Consumption

Year	MMTCE	Tg
1990	1.6	5.7
1991	1.2	4.5
1992	1.5	5.5
1993	1.7	6.1
1994	1.8	6.7
1995	2.0	7.2
1996	1.4	5.1

cline, emissions from ethanol have steadily increased through 1995. From 1995 to 1996, however, ethanol consumption declined by 29 percent. Overall, from 1990 to 1996, emissions of CO_2 decreased by 9.8 percent. Again, emissions from ethanol consumption are not included under the Energy sector because the corn from which ethanol is derived is of biogenic origin.[9]

Ethanol production dropped sharply in the middle of 1996 because of short corn supplies and high prices. Plant output began to increase toward the end of the growing season, reaching close to normal levels at the end of the year. However, total 1996 ethanol production fell far short of the 1995 level (EIA 1997b).

Methodology

Woody biomass emissions were estimated by converting U.S. consumption data in energy units (17.2 million Btu per short ton) to megagrams (Mg) of dry matter using EIA assumptions. Once consumption data for each sector were converted to megagrams of dry matter, the carbon content of the dry fuel was estimated based on default values of 45 to 50 percent carbon in dry biomass. The amount of carbon released from combustion was estimated using 87 percent for the fraction oxidized (i.e., combustion efficiency). Ethanol consumption data in energy units were also multiplied by a carbon coefficient (18.96 mg C/Btu) to produce carbon emission estimates.

Data Sources

Woody biomass consumption data were provided by EIA (1997a) (see Table 2-30). The factor for converting energy units to mass was supplied by EIA (1994). Carbon content and combustion efficiency values were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Uncertainty

The combustion efficiency factor used is believed to under estimate the efficiency of wood combustion processes in the United States. The IPCC emission factor has been used because better data are not yet available. Increasing the combustion efficiency would increase emission estimates. In addition, according to EIA (1994) commercial wood energy use is typically not reported because there are no accurate data sources to provide reliable estimates. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Emissions from ethanol were estimated using consumption data from EIA (1997a) (see Table 2-31). The carbon coefficient used was provided by OTA (1991).

Table 2-30: Residential and Industrial Biomass Consumption (Trillion Btu)

Year	Industrial	Residential
1990	1,562	581
1991	1,528	613
1992	1,593	645
1993	1,625	548
1994	1,673	537
1995	1,698	596
1996	1,784	595

Table 2-31: Ethanol Consumption

Year	Trillion Btu
1990	82
1991	65
1992	79
1993	88
1994	97
1995	104
1996	74

9 Emissions and sinks of biogenic carbon are accounted for under the Land-Use Change and Forestry sector.